Alberta Energy Regulator

Swan Hills Synfuels Ltd
Well Blowout
October 10, 2011

AER Investigation Report

February 25, 2014

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Published by
Alberta Energy Regulator
Suite 1000, 250 – 5 Street SW
Calgary, Alberta
T2P 0R4

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1 Incident Description

At 1:30 p.m. on October 10, 2011,[1] Swan Hills Synfuels Ltd. (SHS) notified the AER St. Albert Field Centre (SAFC) of a well blowout, explosion, and fire at its injection well associated with its in situ coal gasification (ISCG) demonstration project (demo project). The incident location, Legal Subdivision 16, Section 04, Township 065, Range 11, West of the 5th Meridian (16-04-065-11W5M), is in a rural wooded area approximately 17 kilometres (km) southwest of the town of Swan Hills. At 12:29 p.m. on October 10, 2011, a facility contract operator employed by Cobra Maintenance LP on behalf of SHS (the licensee) was on site when the blowout and explosion occurred.

Based on the information supplied by SHS, the SAFC activated its emergency operations centre and designated the incident as a level-1 emergency using the AER Assessment Matrix for Classifying Incidents in *Directive 071: Emergency Preparedness and Response Requirements for the Petroleum Industry*.

At 12:29 p.m. on October 10, 2011, the facility contract operator was on site making adjustments to wellhead valves and monitoring pressures. The operator was making a radio call to the control room operator and was a safe distance from the injection well when the blowout and explosion occurred. The operator activated the emergency shutdown station located at the lease boundary upon evacuation of the lease. No injuries resulted from incident; however, the blowout resulted in significant damage to the injection well, wellhead, and associated surface equipment.

The incident occurred approximately six days after there was an operational change to the injection well. As a result of the change, a series of cascading events took place (detailed later in this report) that ultimately resulted in hot synthesis gas (syngas) and oxygen being drawn into the vertical annulus of the injection well, causing the autoignition of the combustible mixture. The ensuing pressure wave severed the wellhead and ejected the tubulars and debris from the well onto the well lease and into the surrounding forest, mostly to the northwest of the injection well. No off-site liquid releases or off-site air emissions were detected as a result of the incident.

SHS immediately activated its corporate emergency response plan and contracted well control and cleanup operations. As a result of the downhole explosion and ejection of tubulars and debris from the well, a number of small fires were started in the surrounding forest. Although SHS contacted the Alberta Wildfire Hotline, SHS was able to extinguish all of the fires associated with the event

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* On June 17, 2013, the *Responsible Energy Development Act* was proclaimed, and the AER was created. Although events may have taken place under its predecessor, the Energy Resources Conservation Board, for simplicity, "the AER" will be used throughout.

[1] See AER Field Inspection System (FIS) number 20112027 for notification time.

with on-site personnel and on-site fire suppression equipment. Once the initial event occurred, gas associated with the release flowed at a minimal and intermittent rate from the severed wellhead. Well control and cleanup operations continued until October 15, 2011, when a temporary wellhead was installed by Hellfire Suppression Services (HSS). The AER then called down the incident.

The demo project has remained suspended since the incident and SHS has abandoned the injection and production wells in accordance with AER requirements.

2 Project Description and Operational History

SHS, a private energy development company founded in 2005 that is based out of Calgary, Alberta, owns and operates Alberta's first ISCG demonstration project. SHS has secured deep—about 1400 metres (m) into the Medicine River Coal Zone in the Mannville Group—unmineable coal reserves in the Swan Hills area with the goal of using ISCG technology to produce raw syngas to be used as a fuel source for low emission power generation.

In 2009, SHS developed and constructed the ISCG demo project, which is located about 17 km southwest of the town of Swan Hills, Alberta. The demo project consists of one commercial-scale, horizontal injection well (see figure 1) with associated injection facilities, located at LSD 16-04-065-11W5M (injection site), and one commercial-scale, vertical production well with associated gas production facilities, located 1.6 km due north of the injection site at LSD 16-09-065-11W5M (production site). A monitoring site consisting of an observation well with a microseismic monitoring array is located between the two sites at 09-09-065-11W5M. SHS had been operating the demo project, producing syngas and gathering important operational and technical information, from 2009 until the date of the incident.

The subject ISCG process takes place about 1400 m below surface in the Mannville coal zone. The process involves drilling a pair of wells, one horizontal and one vertical, into the target coal zone. The horizontal injection well is used for injecting a mixture of oxygen and water into the formation. The oxygen supports combustion, which brings the injected water to a super-heated state where steam is generated. The combination of formation pressure, elevated temperature, and steam creates the right conditions to gasify the coal. The coal is converted in situ into raw syngas, which consists mainly of methane, carbon dioxide, carbon monoxide (CO), and hydrogen. The raw syngas is then produced to the surface through the vertical production well.

The ISCG reaction process is initiated at the "toe" of the horizontal injection well. As the coal is gasified in the combustion area or chamber, the burner tip, installed at the end of the movable 60.3 millimetre (mm) coiled tubing, is drawn back through the 114 mm casing (casing) used for water injection in a step-wise process towards the heel of the injection well. This process uses the previous chambers as a path for the flow of raw syngas to the production well (see figure 2).

The demo project is designed to produce about 113 000 cubic metres (m^3) per day of syngas from the gasification of about 75 tonnes per day of coal.

3 Incident Response

SHS initiated its emergency response plan upon first indication of the incident from operations staff at the site. SHS contracted Scott Safety Services Ltd. (SSSL) to assist in the initial response, which included setting up roadblocks and security, providing ambulance services, supplying a fire truck to aide in fire suppression services if the need arose, supplying a gas monitoring system capable of monitoring for hydrogen sulphide (H_2S), methane, sulphur dioxide (SO_2), supplying an air trailer with self-contained breathing apparatus, and establishing a safety watch for people working on the lease.

SHS also contracted HSE Integrated Ltd. (HSE) to provide a mobile air monitoring unit (AMU) capable of monitoring for H_2S, and SO_2. The monitoring unit did not arrive until October 11 and the Alberta Environment[2] (AENV) mobile air monitoring laboratory (MAML) was deployed to the site on October 10.

HSS was contracted and provided two fire trucks, technical expertise on removing debris from around the well to allow access for capping operations, and technical expertise on repairing the wellhead, capping, and well abandonment operations.

The initial phase of the response, from October 10 to October 15, 2011, involved

- ensuring safe conditions around the well, including continuous air monitoring,
- removing all associated wellhead and injection equipment and debris to facilitate access to the well, and
- preparing the lease for well control operations, including digging a trench and bell hole to manage water flowing intermittently from the open casing stub and installing a temporary wellhead for well control operations.

The next phase of the operation, from October 15 to October 23, 2011, involved cutting the 244.5 mm surface casing below the original casing bowl, cutting the 177.8 mm casing above the 244.5 mm surface casing stub, welding a 177.8 mm x 229 mm casing bowl onto the 177.8 mm casing, then installing a temporary wellhead on the well for control and abandonment operations.

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[2] Alberta Environment has since been merged with Sustainable Resource Development. For this report, the two will be treated as separate entities, which they were at the time of the incident.

From October 24 to November 12, 2011, fishing operations to remove pipe remaining in the wellbore proved unsuccessful, and from November 12 to 15, 2011, well abandonment operations were carried out. SHS contracted HSS to conduct these operations.

3.1 Regulatory Response

Staff from the SAFC, the AER Air Monitoring Unit, and the AER Field Incident Response Support Team were present at the incident site from October 10 to October 16, 2011. Representatives from Alberta Sustainable Resource Development (the land manager), AENV (which deployed its MAML from October 10 to October 11, 2011), and Workplace Health and Safety also visited the incident site. The AER did not issue a press release, and the incident received no media attention.

3.2 Air Monitoring

The AER's AMU and AENV's MAML monitored the air from October 10 until October 11, at which time SSSL and HSE, contracted by SHS, took over the monitoring.

SSSL set up a gas monitoring system on the lease. The system consisted of four remote sensors located at various points around the lease. Each sensor was equipped to monitor for methane, H_2S, and SO_2.

HSE provided a mobile AMU that was stationed at the roadblock immediately crosswind of the event location. HSE's AMU monitored continuously until the well was capped.

Air monitoring records included in SHS's information package do not indicate any hourly exceedance of the Alberta Ambient Air Quality Objectives for the duration of the monitoring.

3.3 Soil Monitoring

No soils off location were affected by this incident. Following the well blowout, produced water associated with the injection well would periodically bubble and mist due to gas escaping intermittently from the well in an area just south of the well centre. Vacuum trucks managed the produced water, primarily contained within the cellar around the surface casing. Approximately 16 m^3 was hauled to Canadian Crude Separators Inc.'s Judy Creek Waste Management Facility and 8 m^3 hauled to Palko Environmental Services Ltd. waste management facility for disposal. An area of approximately 600 m^2 was scraped with a caterpillar where produced water affected soil in close proximity to the wellhead. The affected soils were stored on site in two separate piles about 5 m by 5 m each. These soil piles were sampled and met the natural area guidelines for fine soils set out in the *Alberta Tier 1 Soil and Groundwater Remediation Guidelines*. Excavated soils remained on site for backfilling once well control operations were completed. Clear Environmental Solutions, contracted by SHS, conducted the monitoring and testing.

4 Root Cause Analysis

4.1 SHS Report Analysis

SHS commissioned an investigation team to determine the cause of the incident. The investigation team included personnel from SHS, Arc Metallurgical, Frontier Engineering, Tri-Action Consulting, and the University of Alberta. The investigation team prepared a report dated February 6, 2012, and three supplemental information request responses dated April 2, May 2, and June 26, 2012. The report and supplemental information requests are referred to as the SHS report.

The SHS report provided root cause analyses around the following events:

- Ignition inside the casing on October 10, 2011, at 12:28:59 p.m.
- Ignition outside the casing on October 8, 2011, at 11:52 p.m.
- Ignition inside the casing on October 8, 2011, at 11:52 p.m.
- Ignition outside the casing on October 8, 2011, at 5:02 p.m.
- Ignition inside the casing on October 8, 2011, at 5:02 p.m.
- Coiled tubing breach at the weld location

Each root cause analysis had between 17 and 19 potential cause paths. From these cause paths, the SHS report concluded that the following was the most likely sequence of events (see also figure 3).

Table 1. Most likely sequence of events

Date	Sequence	Event
February 20, 2011	1	• Ignition downstream of November 2010 ignition burner location • Casing thermally compromised • Coiled tubing stuck in injection well
July 21, 2011	2	• Coiled tubing filled with water during repairs • Coiled tubing insufficiently purged with nitrogen • Oxygen and water mixture caused coiled tubing to partially corrode, especially in low points along well trajectory
October 4, 2011	3	• Water injection rate decreased, causing laminar flow in water annulus • Oxygen and syngas migrated into water annulus • Oxygen and water mixture, as well as syngas, caused casing and coiled tubing to corrode
October 7, 2011		
2:02 a.m.	4	• Casing breached due to corrosion and thermal impacts • Oxygen and syngas migrated farther into the water annulus
4:55 a.m.	5	• Syngas autoignited inside the water annulus and upstream of the burner
4:37 p.m.	6	• Coiled tubing collapsed due to ignition and corrosion
4:37–6:14 p.m.	7	• Pressure buildup in coiled tubing and ignition line

Date	Sequence	Event
6:14 p.m.	8	• Coiled tubing breached at weld, located at about 2128 metres measured depth (m MD) and at a low point in well trajectory • Oxygen migrated from oxygen annulus into water annulus • Oxygen and water mixture caused casing and coiled tubing to corrode
October 7–8, 2011	9	• Oxygen migrated from coiled tubing breach at weld (low point in well trajectory) to high point in well trajectory • Oxygen and water mixture caused casing and coiled tubing between weld and high point to corrode • Casing and coiled tubing breached due to corrosion • Oxygen migrated from water annulus into formation
October 8, 2011		
5:02 p.m.	10	• Coalbed methane autoignited in the formation at about 2138 m MD
11:52 p.m.	11	• Syngas or coalbed methane autoignited in the formation at about 1804 m MD
October 9, 2011	12	• Gasification occurred in the formation
	13	• Water migrated from water annulus into oxygen annulus at about 1804 m MD (high point in well trajectory)
	14	• Water migrated from high point to injection well heel (low point in well trajectory) • Oxygen and water mixture caused coiled tubing between high point and injection well heel to corrode
October 10, 2011		
12:30 a.m.	15	• Coiled tubing breached at the heel, located at about 1531 m MD • Oxygen migrated from oxygen annulus into vertical portion of water annulus
	16	• Oxygen displaced water in water annulus
12:25 p.m.	17	• Surface valve on water injection line opened • Hot syngas drawn into water annulus
12:28:59 p.m.	18	• Hot syngas autoignited in water annulus at about 1461 m MD • Coiled tubing collapsed due to ignition
12:29:08 p.m.	19	• Ignition line ignited at about 1531 m MD

4.2 AER Analysis

The AER performed an independent root cause analysis and reviewed the SHS report's most likely sequence of events. The AER accepts this sequence of events with the following exception:

- The fuel source for ignition in the formation on October 8, 2011, at 5:02 p.m. may have been syngas that flowed via the uncemented space between the casing and the formation.

The AER disagrees, however, with the SHS report's underlying causes. The report focused on the causes that directly resulted in the events that occurred (e.g., decreased water injection rate, opened surface vent). The AER focused on the actions that SHS took that generated those causes.

The AER concludes that the most likely sequence of events were caused by SHS's

- failure to follow ignition procedures,
- failure to perform appropriate calculations prior to modifications,

- failure to reengineer operating procedures prior to modifications,
- inadequate operating procedures to identify and mitigate abnormal operations,
- failure to shut down the operation during abnormal operations,
- inappropriate start-up procedures, and
- failure to redesign and manage dynamic injection well conditions.

These root causes are further discussed in section 5.

5 Investigation Findings

The SHS report provided a description of the events believed to have contributed to the incident. These events, and supporting evidence, are presented in this section.

5.1 Burner Position

5.1.1 SHS Report Findings

The SHS report concluded that the burner position during the ignitions in November 2010 and on February 20, 2011, contributed to the incident.

Table 2. Observations pertaining to the burner position

Date	Observation
November 2010	• Burner located about 11 m from injection well toe • Ignition conducted • Low temperatures experienced during ignition
January 2011	• Casing pup joint milled
February 20, 2011	• Burner located about 7 m from injection well toe • Ignition conducted • High temperatures experienced during ignition • Coiled tubing unsuccessfully retracted • Burner stuck between 9 m and 14 m from injection well toe

For ignition, a burner should be positioned as close as possible to the injection well toe. During the November 2010 ignition, the burner was located about 11 m back from the toe and could not be positioned closer because it was unable to pass a small diameter pup joint in the casing.

The SHS report indicated the following:

- High ignition temperatures will compromise the structural integrity of the casing.
- The burner is likely to get stuck when positioned past a previously ignited zone.
- Low temperatures were experienced during the November 2010 ignition.

Because of the low temperatures during the November 2010 ignition, SHS believed that the structural integrity of the casing was not compromised. As a result, SHS determined that it was acceptable to mill the restrictive pup joint and insert the burner closer to the injection well toe.

The SHS report concluded the following:

- Contrary to SHS's original belief, the low temperatures experienced during the November 2010 ignition compromised the structural integrity of the casing.
- The high temperatures experienced during the February 20, 2011, ignition further compromised the structural integrity of the casing.
- The casing likely collapsed near the overlapping ignition zones after the February 20, 2011, ignition.
- The coiled tubing became stuck because of the collapsed casing.

The SHS report recommended that the burner not be positioned past a previous ignition zone, reducing the risk of the coiled tubing becoming stuck by collapsed casing.

5.1.2 AER Findings

The AER reviewed the ignition procedure provided by SHS, which indicated that the burner would be retracted towards the injection well heel for each new gasification chamber (or ignition).

The AER concludes that SHS positioned the burner past a previous ignition point because

- SHS incorrectly assumed that the casing's structural integrity would not be compromised by low ignition temperatures,
- best practices state that the burner should be positioned as close as possible to the injection well toe, and
- the milling operation allowed the burner to be inserted closer to the injection well toe.

The AER accepts the sequence of events in the SHS report. The AER concludes that SHS's disregard for its ignition procedure contributed to

- the casing's structural integrity being thermally compromised by overlapping ignition zones, and
- the casing collapsing, resulting in stuck coiled tubing.

5.2 Water Annulus Flow Regime

5.2.1 SHS Report Findings

The SHS report concluded that decreasing the water injection rate changed the water annulus flow regime to laminar flow, which initiated the incident.

Table 3. Observations pertaining to a change in the water annulus flow regime

Date	Observation
September 1, 2011	• Water and oxygen annulus and ignition line pressures increased • Syngas production rate decreased
October 4, 2011	• Water injection rate decreased
October 7, 2011	• Water and oxygen annulus pressures and ignition line pressure decreased at 2:02 a.m. (first time since September 1, 2011) • No change in syngas production rate • Water and oxygen annulus pressures spiked at 4:55 a.m. • Oxygen annulus and ignition line pressures increased at 4:37 p.m., deviating from the water annulus pressure (first time ever)

Because the water and oxygen annulus and ignition line pressures increased when the syngas production rate decreased, the SHS report concluded that there was a reduction in communication between the injection and production well. The SHS report indicated that the water injection rate was decreased to heat up the gasification chamber and improve well-pair communication. While this method is valid and has been used successfully in the past, the water annulus flow regime became laminar after SHS decreased the water injection rate on October 4, 2011.

The SHS report concluded that the following occurred as a result of the laminar flow in the water annulus:

- Oxygen and syngas migrated into the water annulus.
- The structural integrity of the coiled tubing and the casing were thermally compromised by
  - hot syngas, and
  - a reduced water injection rate.
- The casing's inner diameter and the coiled tubing's outer diameter were corroded by
  - hot syngas, and
  - the oxygen and water mixture.
- The casing likely breached upstream of the burner on October 7, 2011.

The SHS report provided evidence supporting the casing breach. The decrease in the water and oxygen annulus and ignition line pressures would have normally indicated improved well-pair communication had the syngas production increased. Because the syngas production remained

constant, SHS determined that an alternate flow path to the formation had developed, causing the pressure decrease. The SHS report concluded that the most likely flow path was a casing breach upstream of the burner and that the following occurred as a result:

- Syngas autoignited inside the water annulus at 4:55 a.m. on October 7, 2011.
- The coiled tubing likely collapsed around 4:37 p.m.

The SHS report provided evidence supporting the ignition and coiled tubing collapse. The water and oxygen annulus pressures spiked and no microseismic events (MSEs)[3] were recorded at 4:55 a.m., indicating that an ignition occurred and that it was contained by the casing. The oxygen annulus and ignition line pressures increased and deviated from the water annulus pressure at 4:37 p.m., indicating a blockage in the coiled tubing, likely a collapse.

The SHS report made the following recommendations:

- Establish minimum and maximum flow rates and pressures for each injection well annulus to prevent fluid migration.
- Provide operator training on recognizing potential coiled tubing or casing breaches using pressure trends.

5.2.2 AER Findings

The AER concludes the following:

- Reducing the water injection rate is an acceptable procedure to heat up the gasification chamber and improve well-pair communication.
- The water annulus flow regime is laminar at low water injection rates.
- The pressure trends support the casing breach, ignition in the water annulus, and coiled tubing collapse.

The AER accepts the sequence of events in the SHS report. The AER concludes that laminar flow in the water annulus contributed to

- oxygen and syngas migrating into the water annulus,
- the casing and coiled tubing being thermally compromised and corroded,
- the casing being breached,
- oxygen and syngas migrating farther into the water annulus,

[3] A microseismic event is a release of energy in the form of seismic waves caused by fracturing or deformation within a rock mass.

- syngas autoigniting inside the water annulus, and
- the coiled tubing collapsing.

The AER concludes that the sequence of events resulting from laminar flow in the water annulus was ultimately caused by SHS's failure to perform fluid flow calculations prior to lowering the water injection rate.

5.3 Nitrogen Purge

5.3.1 SHS Report Findings

The SHS report concluded that the nitrogen purge on July 21, 2011, which did not completely remove water from the coiled tubing, contributed to the incident.

Table 4. Observations pertaining to an insufficient nitrogen purge

Date	Observation
December 2010	• Coiled tubing welded 650 m back from burner
February 20, 2011	• Coiled tubing unsuccessfully retracted • Burner stuck between 9 m and 14 m from injection well toe
July 4–20, 2011	• Coiled tubing unsuccessfully retracted • Indentation found in coiled tubing • Coiled tubing filled with water and brine during indentation repairs
July 21, 2011	• Coiled tubing purged with nitrogen
July 22, 2011	• Ignition conducted • Oxygen injection started
August 12, 2011	• Pure oxygen injection started[4]
October 7, 2011	• Oxygen annulus and ignition line pressures increased at 4:37 p.m., deviating from the water annulus pressure (first time ever) • Water injection rate increased at 6:01 p.m. • Water annulus pressure spiked at 6:14 p.m. • Oxygen annulus and ignition line pressures decreased at 6:14 p.m., no longer deviating from the water annulus pressure • Water injection rate decreased at 7:46 p.m.
October 8, 2011	• Water annulus and oxygen annulus pressures spiked at 5:02 p.m. • Two MSEs occurred simultaneously at 5:02 p.m.

The SHS report indicated that the coiled tubing was normally purged with nitrogen at surface. As the coiled tubing was stuck, it had to be purged with nitrogen while installed. SHS assumed that an industrial-nitrogen pumper truck and maximum nitrogen injection rates would sufficiently purge the coiled tubing of water. SHS acknowledged that the influence of downhole pressure on the nitrogen purge rate was not sufficiently considered.

[4] Prior to pure oxygen injection, a blend of nitrogen and oxygen was injected.

The SHS report concluded the following:

- The nitrogen purge on July 21, 2011, did not completely remove water from the coiled tubing, especially in the coiled tubing's low points.
- The coiled tubing's inner diameter partially corroded when oxygen injection started on July 22, 2011.
- The weld 650 m back from the burner was more susceptible to corrosion than the rest of the coiled tubing because it was already heat affected and at a low point.
- The coiled tubing likely breached at the weld location because of the increasing pressure from the upstream coiled tubing collapse and corrosion from the oxygen and water mixture.

The SHS report provided evidence supporting the coiled tubing breach. The water annulus pressure spiked and the oxygen annulus and ignition line pressures decreased, no longer deviating from the water annulus pressure, at 6:14 p.m. on October 7, 2011. These pressure trends indicated that the coiled tubing was open to the water annulus via a coiled tubing breach.

The SHS report also concluded the following:

- Oxygen migrated from the oxygen annulus to the lower-pressure water annulus via the coiled tubing breach.
- The casing corroded from the high partial-pressure oxygen and water mixture within a day (worst-case scenario).
- Oxygen migrated from the water annulus to the lower-pressure formation via the corroded casing.
- Coalbed methane autoignited in the formation at 5:02 p.m. on October 8, 2011.

The SHS report provided evidence supporting the ignition. The water and oxygen annulus pressures spiked and two MSEs were recorded. Analysis of the MSE data determined an ignition occurred at about 2138 m MD.

The SHS report recommended that the coiled tubing management procedure be modified to incorporate the nitrogen purge criteria for installed coiled tubing.

5.3.2 AER Findings

The AER concludes the following:

- SHS failed to perform any engineering calculations to ensure that the nitrogen purge would be sufficient to completely remove water from the installed coiled tubing.
- The welding procedure used for the weld 650 m back from the burner was appropriate.

- The corrosion rate analysis in the SHS report was reasonable.
- The pressure trends support the coiled tubing breach, oxygen migration into the water annulus and formation, and ignition in the formation.
- The microseismic analysis supports the ignition in the formation.

The AER accepts the sequence of events in the SHS report, excluding the fuel source for the ignition in the formation at 5:02 p.m. on October 8, 2011. The AER believes that the fuel source may have been syngas, which flowed back via the uncemented space between the casing and the formation. The SHS report maintained that

- syngas was an unlikely fuel source for this ignition because of the p-trap principle, and
- p-traps would prevent gas from flowing back in the water annulus provided that the coiled tubing and casing were intact and the water flow rate was sufficient.

Therefore, the casing and formation would need to be intact and the nitrogen purge would need to be sufficient to prevent syngas flow black in the uncemented space between the casing and formation. The SHS report was unable to provide evidence showing that coal did not slough in between the intermediate casing and the ignition location. If coal had sloughed in between these two points, nitrogen flow may have been limited and syngas may have flowed back via the uncemented space.

The AER concludes that the insufficient nitrogen purge contributed to

- the coiled tubing partially corroding when oxygen injection started,
- the coiled tubing breaching at the weld,
- oxygen migrating into the water annulus,
- the casing corroding,
- oxygen migrating into the formation, and
- syngas or coalbed methane autoigniting in the formation.

The AER concludes that the sequence of events resulting from the insufficient nitrogen purge was ultimately caused by SHS's failure to reengineer its coiled tubing dry-out procedure for installed coiled tubing.

5.4 Well Trajectory

5.4.1 SHS Report Findings

The SHS report concluded that the well trajectory contributed to the incident.

Table 5. Observations pertaining to the well trajectory

Date	Observation
October 7, 2011	• Water annulus pressure spiked at 6:14 p.m. • Oxygen annulus and ignition line pressures decreased at 6:14 p.m., no longer deviating from the water annulus pressure • Water injection rate decreased at 7:46 p.m.
October 8, 2011	• Water and oxygen annulus pressures spiked at 5:02 p.m. • Two MSEs occurred simultaneously at 5:02 p.m. • Water and oxygen annulus pressures spiked at 11:52 p.m. • One MSE occurred at 11:52 p.m.
October 9, 2011	• Fourteen MSEs occurred between 12:16 a.m. and 9:45 a.m. • One MSE occurred at 6:17 p.m.
October 10, 2011	• Heel temperature slightly increased then decreased at 12:30 a.m. and 12:37 a.m. respectively • Heel temperatures were about 2–5°C cooler than normal • Water annulus pressure started increasing independent of oxygen annulus and ignition line pressures at 12:37 a.m.

The SHS report indicated that high and low points in the well trajectory are

- typical with the available drilling technology,
- expected when drilling along or near the bottom of undulating coal seams,[5] and
- normally beneficial, creating p-traps that prevent gas from flowing back in the annulus provided that the coiled tubing and casing are intact and the water flow rate is sufficient.

As described in section 5.3.1, the spike in the water annulus pressure and decrease in the oxygen annulus and ignition line pressures indicated a coiled tubing breach, which likely occurred at a low point in the well trajectory. The SHS report concluded the following:

- Oxygen buoyantly migrated from the coiled tubing breach at a low point in the well trajectory to a high point in the well trajectory.
- The casing corroded from the oxygen and water mixture between the coiled tubing breach and the high point in the well trajectory.
- Oxygen migrated from the water annulus to the lower-pressure formation via the corroded casing.
- Syngas or coalbed methane autoignited in the formation near a low point in the well trajectory at 5:02 p.m. and near a high point in the well trajectory at 11:52 p.m. on October 8, 2011.
- The ignition at 11:52 p.m. started gasification in the formation.

[5] ISCG operators drill along or near the bottom of the coal seam to maximize resource recovery.

The evidence from the SHS report supporting an ignition at 5:02 p.m. on October 8, 2011, is summarized in section 5.3.1. The SHS report also provided evidence supporting the ignition at 11:52 p.m. on October 8, 2011, and the resulting gasification. The water and oxygen annulus pressures spiked and an MSE was recorded at 11:52 p.m. on October 8, 2011, followed by fifteen MSEs on October 9, 2011. Analysis of the MSE data determined that an ignition occurred near a high point in the well trajectory, at about 1804 m MD, which started gasification in the formation.

The SHS report also concluded the following:

- The coiled tubing corroded from the outside in at the high point in the well trajectory.
- The gravitational force acting on the water at the high point in the well trajectory was greater than the dragging force of injected oxygen in the coiled tubing. Therefore, water entered the coiled tubing at the high point.
- Water migrated inside the coiled tubing from the high point and travelled through the coiled tubing to the heel of the well, which was at a low point in the well trajectory.
- The coiled tubing corroded from the inside out from the oxygen and water mixture.
- The coiled tubing breached at the injection well heel.
- Oxygen migrated into the vertical section of the water annulus via the coiled tubing breach.

The SHS report provided evidence supporting the breaching of the coiled tubing at the well heel and subsequent oxygen migration. The normally steady heel temperature decreased on October 10, 2011, indicating the presence of a cooler substance, likely the injected oxygen. The water annulus pressure also started to increase, indicating that oxygen started displacing water in the vertical section of the water annulus.

5.4.2 AER Findings

The AER concludes the following:

- The injection well should follow the bottom of the coal seam to maximize resource recovery.
- The p-trap concept is valid.
- The well trajectory would not have been a contributing cause had the coiled tubing and casing been intact and the water flow rate sufficient.
- The corrosion rate analysis in the SHS report was reasonable.
- The analysis of water migration into the coiled tubing was reasonable.
- The pressure trends support the ignition and coiled tubing breach at the heel.
- The microseismic analysis supports the ignition in the formation.

- Syngas or coalbed methane were potential fuels for the ignition in the formation.

The AER accepts the sequence of events in the SHS report. The AER concludes that the well trajectory contributed to

- oxygen in the water annulus migrating from the low point in the well trajectory to the high point in the well trajectory,
- the casing and coiled tubing corroding between the low point and high point,
- oxygen migrating into the formation,
- syngas or coalbed methane autoigniting in the formation,
- water migrating into the coiled tubing at the high point and flowing to the injection well heel,
- the coiled tubing being breached at the heel, and
- oxygen migrating into the vertical section of the water annulus.

5.5 Water-Injection-Line Vent

5.5.1 SHS Report Findings

The SHS report considered the slightly opened 19.05 mm vent on the water injection line to be the triggering event, ultimately causing the incident.

Table 6. Observations pertaining to the opened water-injection-line vent

Date	Observation
June 2, 2011	• Wellhead dog nut leaked nitrogen • Leak could not be repaired because of stuck coiled tubing
October 10, 2011	
12:37–2:20 a.m.	• Water annulus pressure started increasing independent of oxygen annulus and ignition line pressures • Water annulus pressure increased above set point causing high-pressure alarm • Water found in water-injection-line bleed
8:41 a.m.	• Wing valve on water injection line blocked • Water annulus pressure continued to increase • Gas (with low CO, no lower explosive limit [LEL], and no H_2S) found in water-injection-line vent closest to the wellhead
	(continued)
9:06 a.m.	• Gas (no CO, LEL, H_2S) found in every water-injection-line vent and drain between the wellhead and the injection water pump, excluding the pump discharge • Methanol pumped into the water injection line
11:12–11:27 a.m.	• Water found in water injection line up to manifold building • Water found in water injection line up to wellhead vent

Date	Observation
12:02–12:29 p.m.	• Water annulus pressure continued to increase • Wing valve on water injection line opened • Water injection pump tripped on high pressure and mode-1 shutdown initiated • Oxygen pump shut down • Oxygen pump restarted • Water-injection-line vent slightly opened • Water annulus pressure slightly decreased • Incident occurred

The SHS report indicated that the operators

- became aware of an issue when the water annulus pressure increased above its set point, causing a high-pressure alarm;
- assumed that the gas found in the water injection line was nitrogen because of
  - the wellhead dog nut leak, and
  - the readings of no to low CO, no LEL, and no H_2S; and
- slightly opened the 19.05 mm vent on the water injection line to decrease pressure in the line and restart the water injection pump.

Five minutes after opening the 19.05 mm vent on the water injection line, the pressure slightly decreased. However, four minutes later the incident occurred.

The SHS report concluded the following:

- Oxygen completely displaced water from the vertical section of the water annulus.
- When the 19.05 mm vent on the water injection line was slightly opened, syngas was drawn into the water annulus via the corroded casing.
- Syngas autoignited in the vertical section of the water annulus.
- The ignition's pressure wave severed the wellhead and collapsed the coiled tubing.
- The ignition line ignited in the vertical section of the water annulus.
- The ignition's pressure wave or the force of escaping gas ejected the tubing.

The SHS report provided evidence supporting two ignitions. Because of the incident, the pressure monitoring equipment failed, and no pressure spikes were registered. However, two MSEs were recorded. Analysis of the MSE data revealed that an ignition occurred at about 1461 m MD and at about 1531 m MD.

The SHS report also contained a metallurgical analysis of the severed wellhead and ejected tubulars. The metallurgical analysis concluded that

- the wellhead was severed by a pressure wave, originating in the water annulus;
- the coiled tubing collapsed from the syngas autoignition in the water annulus; and
- the ignition line ignited from friction generated by the collapsed coiled tubing.

The SHS report made the following recommendations:

- Develop a procedure for operators to follow when high pressure in the water annulus is encountered.

Prohibit venting during operations to keep the downhole operation isolated from surface pressure and reduce the risk of gas flowback.

5.5.2 AER Findings

The AER concludes the following:

- The efforts made by the operators to obtain well control were valid based on their understanding of what was occurring.
- The operating procedures to deal with high pressure in the annuli were inadequate.
- The shutdown criteria were inadequate, especially considering the project's experimental status.
- The pressure trends support oxygen migration into the water annulus.
- The microseismic and metallurgical analyses support the ignitions.

The AER accepts the sequence of events in the SHS report. The AER concludes that the slightly opened 19.05 mm vent on the water injection line contributed to the

- the water annulus being opened to surface pressure,
- syngas migrating from the higher-pressure formation to the lower-pressure water annulus via corroded casing,
- syngas and oxygen mixing in the vertical section of the water annulus,
- syngas autoigniting in the vertical section of the water annulus,
- a pressure wave severing the wellhead and collapsing the coiled tubing,
- friction, generated by the collapsed coiled tubing, igniting the ignition line, and
- tubing being ejected from the well.

The AER concludes that the sequence of events resulting from the slightly opened 19.05 mm vent on the water injection line was ultimately caused by SHS's inadequate operating procedures to identify and mitigate abnormal operations and failure to shut down the operation during abnormal operations.

In addition, the AER concludes that SHS used poor judgement when deciding to restart the oxygen pump during abnormal operations and after a mode-1 shutdown, especially considering that there was no fluid injected in the water annulus at the time.

5.6 Injection Well and Facility Design

5.6.1 SHS Report Findings

Although the SHS report concluded that no significant injection well and facility design changes were required to prevent a similar incident from occurring, the report made the following recommendations:

- Cement the horizontal section of the 114 mm casing, reducing the risk of casing collapse and fluid migration along the outside of the casing.
- Modify the burner's nozzle design to have higher velocities, reducing the risk for fluid migration into the burner, coiled tubing, and ignition line.
- Change the nitrogen purge on the intermediate casing and water annuli from a flow-control loop to a pressure-control loop, keeping the pressures in the intermediate casing and water annuli higher than the formation pressure. This would ensure that nitrogen would purge the intermediate casing or water annulus if either the intermediate casing or 114 mm casing were breached.
- Maintain a static nitrogen blanket on the intermediate casing annulus, which would be filled with inhibited fresh water, to indicate any casing failures in the vertical section of the injection well.
- Install pressure transmitters at the injection wellhead to provide remote, continuous, real-time surface pressure monitoring of the intermediate casing and water annuli.
- Car-seal close the 19.05 mm water-injection-line vent during operations to keep the downhole operation isolated from surface pressure and reduce the risk of gas flowback.
- Change the location of the nitrogen tie-in to the oxygen line and program the oxygen line's emergency shutdown valve to close during a mode-1 trip. This would ensure that the system will be purged with nitrogen when a mode-1 trip occurs.

5.6.2 AER Findings

The AER concludes that the injection well and facility designs were not factors in the incident, but notes that the design changes recommended in the SHS report may have prevented the incident from occurring.

5.7 Temperature Monitoring

5.7.1 SHS Report Findings

The SHS report indicated that burner thermocouples confirm ignition and provide burner protection. However, the burner thermocouples were damaged prior to the incident.

Table 7. Events leading up to damaged burner thermocouples

Date	Event
July 4–20, 2011	• Several attempts made to retract coiled tubing • Coiled tubing unsuccessfully retracted • Indentation found in coiled tubing • Coiled tubing filled with water and brine during indentation repairs • Water and brine solution damaged burner thermocouples

In July 2011, SHS concluded that the burner thermocouples could be abandoned during the coiled tubing repairs because flow rates, pressure, production well bottomhole temperature, and gas composition could be used to confirm ignition and provide burner protection.

The SHS report made the following recommendations with respect to temperature monitoring:

- Have functional temperature monitoring near the burner during operations to aid in monitoring downhole activities.
- Investigate alternative temperature monitoring technologies for the horizontal section of the injection well.

5.7.2 AER Findings

The AER concludes that inadequate temperature monitoring was not a factor in the incident, but notes that temperature monitoring along the horizontal section may have prevented the incident from occurring.

5.8 Microseismic Monitoring

5.8.1 SHS Report Findings

The SHS report made the following recommendations with respect to microseismic monitoring:

- Analyze the microseismic data daily, with any anomalies reported within 24 hours of occurring. This would reduce the risk of a similar event occurring and provide more up-to-date monitoring of downhole activities.
- Install a microseismic array in the abandoned production well to improve the accuracy of the microseismic data.

5.8.2 AER Findings

Prior to the incident, SHS had its microseismic data analyzed on weekdays. Because the first microseismic event occurred on the Saturday of a long weekend, analysis of the data would not have taken place until October 11, 2011, the day after the incident occurred.

The AER concludes that microseismic monitoring may have prevented the incident from occurring had the data been analyzed every day.

The demo project has a single observation well, about midway between the heel and toe of the injection well. The AER believes that a second observation well, closer to the injection well toe, would improve the accuracy of the microseismic data and record smaller events.

5.9 Wellhead Barriers

5.9.1 AER Findings

A common design principle for high-risk wells is the use of a dual-barrier well design, where the second barrier reduces the risk of well control loss should the primary barrier fail.

The AER concludes the following:

- SHS used a single-barrier injection well and wellhead design.
- The stuck coiled tubing limited wellhead repair.
- The coiled tubing hanger and seal were not set at the time of the incident.
- The coiled tubing pipe slips were used as a primary barrier, although they were actually designed only as temporary working seals.
- A dual-barrier well design may have prevented the incident from occurring.

5.10 Emergency Response

5.10.1 AER Findings

The AER Emergency Planning and Assessment (EPA) Section conducted an emergency preparedness and response audit of SHS's operations in the Swan Hills area to support the incident investigation and determine compliance with the requirements in *Directive 071: Emergency Preparedness and Response Requirements for the Petroleum Industry*.

Based on a review of requested information provided by SHS on March 5, 2012, the EPA Section found SHS to be compliant with *Directive 071*. However, the section did identify the following areas for improvement to SHS's corporate emergency response plan:

- outline incident communication plans and protocols to be used between the command centres, response personnel, and external parties;
- indicate the location of each response position or function; and
- incorporate the communication plan that addresses communication with support services and contains contact information for the service providers hired to assist with managing an incident.

6 AER-Directed Actions

SHS must implement the following recommendations contained in the SHS report:

Operating Procedures

- Do not position the burner past a previous ignition zone, reducing the risk of the coiled tubing becoming stuck by collapsed casing.
- Establish minimum and maximum flow rates and pressures for each injection well annulus to prevent fluid migration.
- Modify the coiled tubing management procedure to incorporate the nitrogen purge criteria for installed coiled tubing.
- Develop a procedure for operators to follow when high pressure in the water annulus is encountered.
- Prohibit venting during operations to keep the downhole operation isolated from surface pressure and reduce the risk of gas flowback.
- Train the operators to recognize potential coiled tubing or casing breaches using pressure trends.
- Analyze the microseismic data daily, with anomalies reported within 24 hours of occurring. This will reduce the risk of a similar event occurring and provide more up-to-date monitoring of downhole activities.

- Include a detailed description of the incident in the operator training manual.

Design and Control

- Cement the horizontal section of the 114 mm casing, reducing the risk of casing collapse and fluid migration along the outside of the casing.
- Modify the burner's nozzle design to have higher velocities, reducing the risk for fluid migration into the burner, coiled tubing, and ignition line.
- Change the nitrogen purge on the intermediate casing and water annuli from a flow-control loop to a pressure-control loop, keeping the pressures in the intermediate casing and water annuli higher than the formation pressure. This will ensure that nitrogen will purge the intermediate casing or water annulus if either the intermediate casing or 114 mm casing are breached.
- Maintain a static nitrogen blanket on the intermediate casing annulus, which will be filled with inhibited fresh water, to indicate casing failures in the vertical section of the injection well.
- Install pressure transmitters at the injection wellhead to provide remote, continuous, real-time surface pressure monitoring of the intermediate casing and water annuli. This is an improvement to the original design and will provide a continuous record of the pressures.
- Car-seal close the 19.05 mm water-injection-line vent during operations to keep the downhole operation isolated from surface pressure and reduce the risk of gas flowback.
- Change the location of the nitrogen tie-in to the oxygen line and program the oxygen line's emergency shutdown valve to close during a mode-1 trip. This will ensure that the system will be purged with nitrogen when a mode-1 trip occurs.
- Have functional temperature monitoring near the burner during operations to aid in monitoring downhole activities. In addition, investigation alternative temperature monitoring technologies for the horizontal section of the injection well.
- Install a microseismic array in the abandoned production well to improve the accuracy of the microseismic data.

The AER also requires SHS to do the following:

- SHS must develop a procedure requiring oxygen injection shutdown at surface during any abnormal operations. The cause of any abnormalities must be determined before oxygen injection is resumed.
- Where appropriate, SHS must complete engineering calculations before implementing any procedural changes (e.g., nitrogen purge with coiled tubing installed versus on the surface, changes to safe operating conditions).

- SHS must submit to the AER a document detailing the procedures to regain well integrity should a primary barrier become compromised.
- SHS must complete the improvements to its corporate emergency response plan identified in section 5.10.1.

7 AER Follow-Up

The AER will follow up with SHS on the actions identified in section 5.10.1 within 30 days of the release of this report.

The AER will follow up with SHS on the actions identified in section 6 prior to SHS resuming its operations. Synfuels have submitted a new ISCG project application to the AER for approval, and the AER approved the application (number 1725405) on March 27, 2013.

Swan Hills Synfuels Coal Gasification Project

Injection Well - SH SYNFUELS 102 SWANHS AA/16-9-65-11 W5M /03

(Surface Location - 16-4-65-11 W5M)

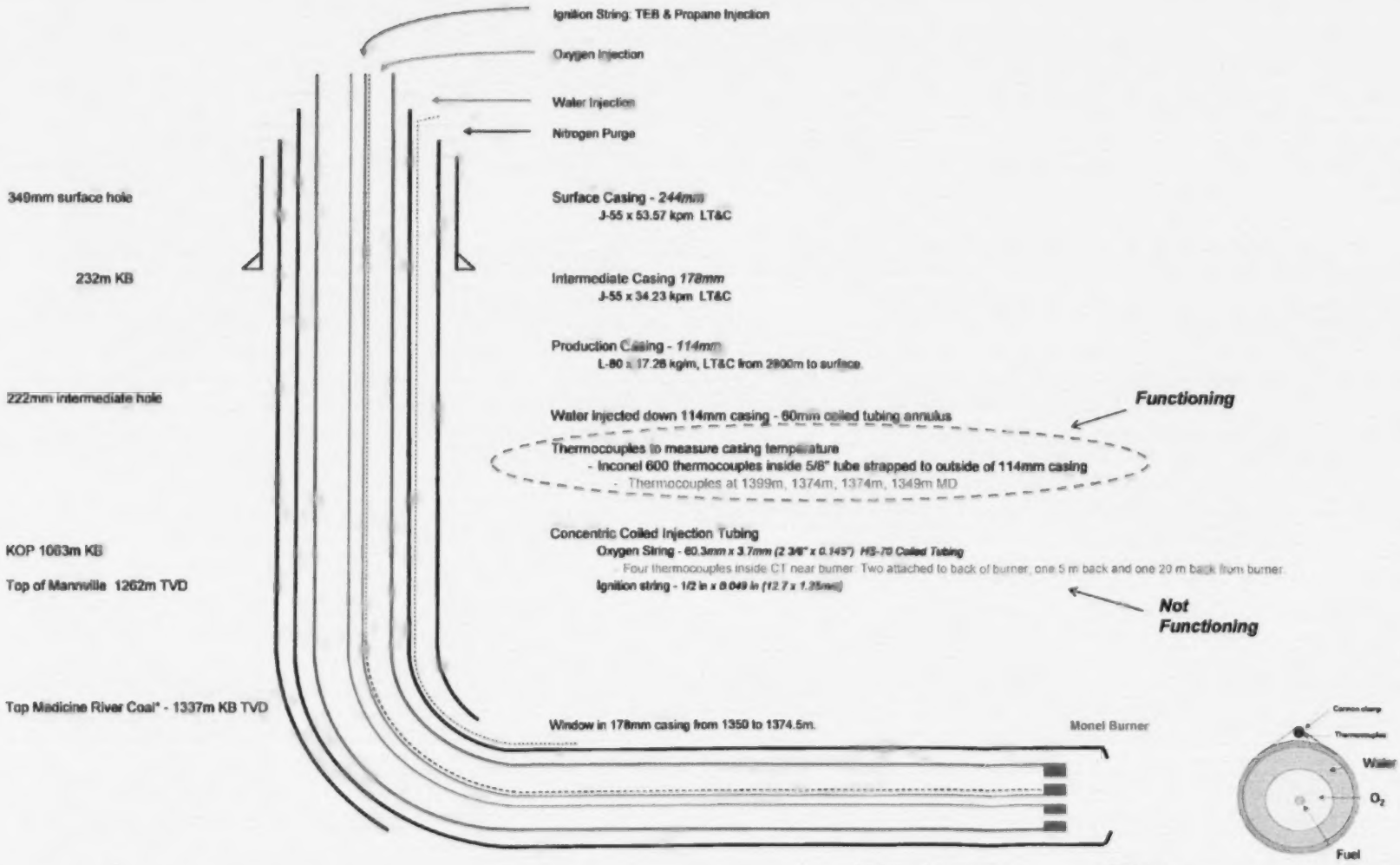
Ignition String: TEB & Propane Injection
Oxygen Injection
Water Injection
Nitrogen Purge
349mm surface hole
Surface Casing - 244mm
J-55 x 53.57 kpm LT&C
232m KB
Intermediate Casing 178mm
J-55 x 34.23 kpm LT&C
Production Casing - 114mm
L-80 x 17.26 kg/m, LT&C from 2800m to surface
222mm intermediate hole
Functioning
Water injected down 114mm casing - 60mm coiled tubing annulus
Thermocouples to measure casing temperature
- Inconel 600 thermocouples inside 5/8" tube strapped to outside of 114mm casing
- Thermocouples at 1399m, 1374m, 1374m, 1349m MD
Concentric Coiled Injection Tubing
Oxygen String - 60.3mm x 3.7mm (2 3/8" x 0.145") HS-70 Coiled Tubing
Four thermocouples inside CT near burner. Two attached to back of burner, one 5 m back and one 20 m back from burner.
Ignition string - 1/2 in x 0.049 in (12.7 x 1.25mm)
KOP 1063m KB
Top of Mannville 1262m TVD
Not Functioning
Top Medicine River Coal* - 1337m KB TVD
Window in 178mm casing from 1350 to 1374.5m.
Monel Burner
Common clamp
Thermocouples
Water
O2
Fuel
Burner Tip at +/- 2774m MD
- TD at 2833m
- Casing Shoe 2800m MD

Figure 1. Injection well schematic (reproduced courtesy of Swan Hills Synfuels Ltd.)

Revised April 2, 2012
Version 01

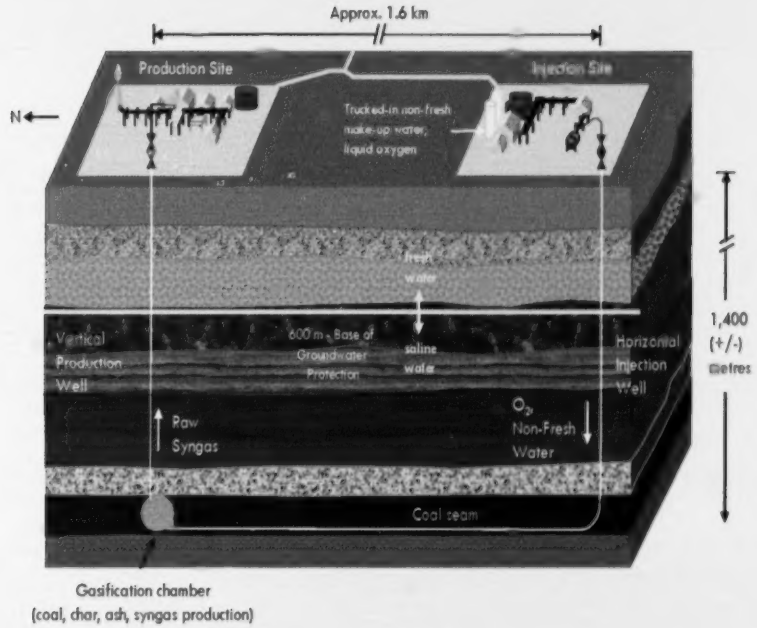

Figure 2. Configuration of the ISCG demo project

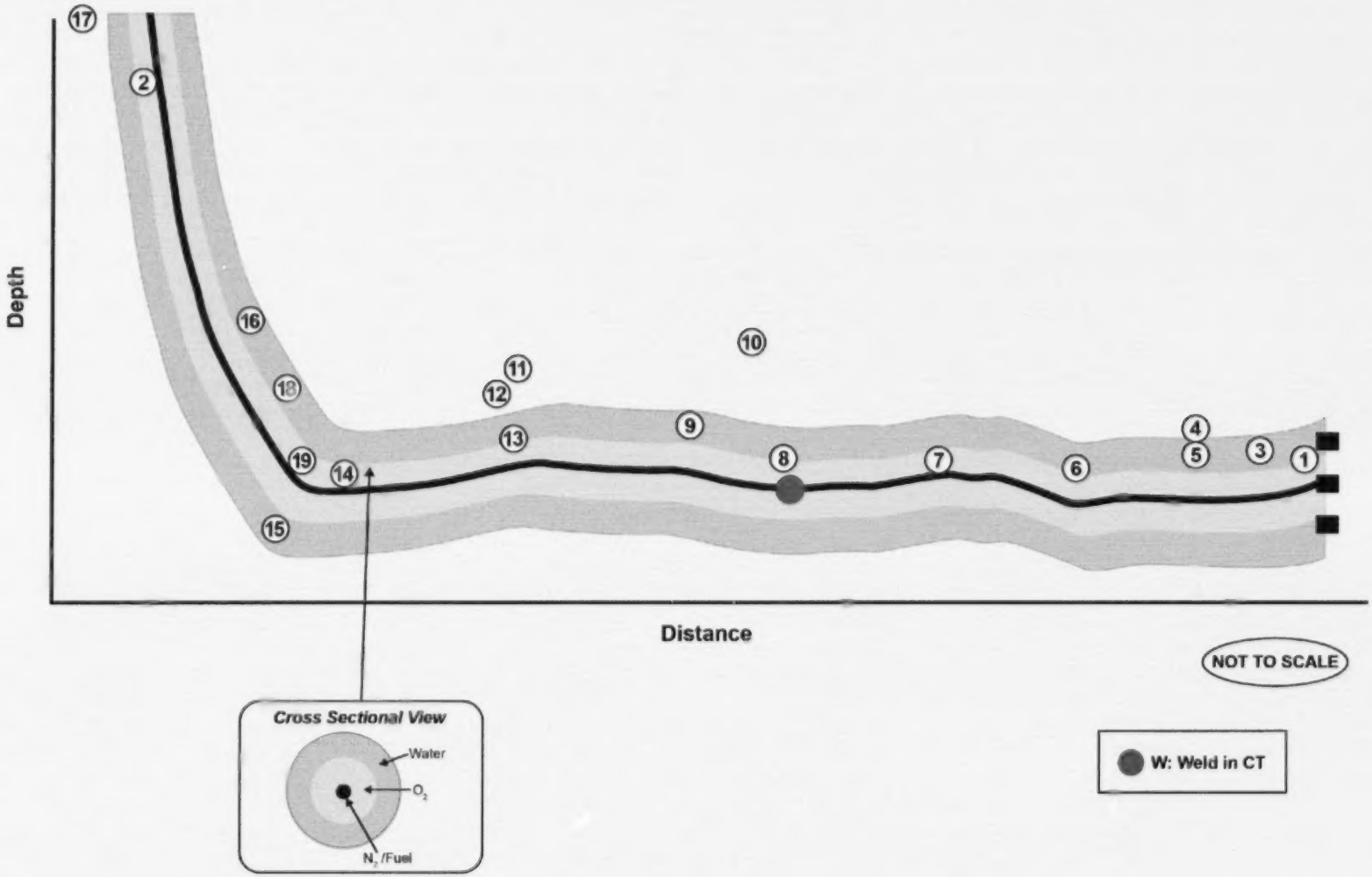

Figure 3. Visual representation of sequence of events.